Chapter D2: Technical Description of Case Study Facilities

This chapter presents technical information related to the case study facilities. Section D2-1 presents detailed Energy Information Administration (EIA) data on the generating units addressed by this case study and within the scope of the Phase II rulemaking (i.e., in-scope facilities). Section D2-2 describes the configuration of the intake structures at the in-scope facilities.

CHAPTER CONTENTS

D2-1 Operational Profiles

Baseline operational characteristics

a. Big Bend

During 1999, the Big Bend power plant operated seven units: four coal-fired steam-electric generators (Units 1, ST2-ST4) that use cooling water withdrawn from Middle Tampa Bay, and three oil-fired gas turbines (Units GT1-GT3) that do not require cooling water. Three of the steam-electric units began operation between 1970 and 1976; the fourth steam unit began operation in 1985.

Big Bend's total net generation in 1999 was 9.1 million MWh. The steam turbine units (Units 1,ST2-ST4) accounted for 99.2 percent of total net generation. The capacity utilization of Big Bend's steam turbine units ranged from 53.7 percent (Unit ST3) to 57.3 percent (Unit ST2).

Table D2-1 presents details for Big Bend's seven units.

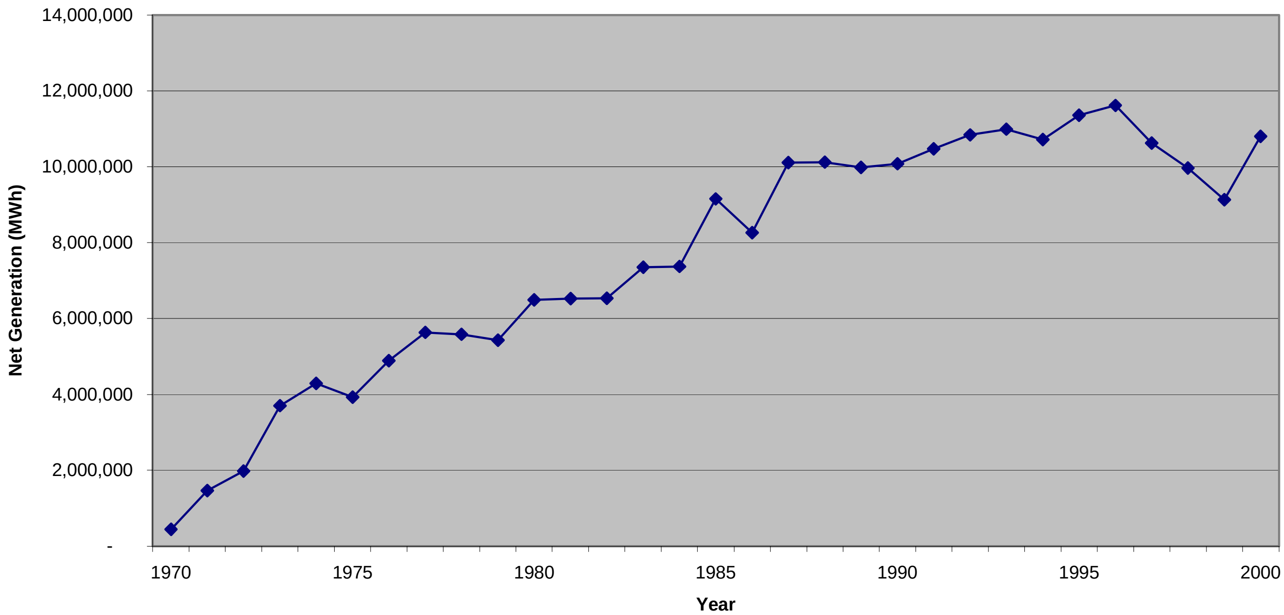
Table D2-1: Big Bend Generator Characteristics (1999)

Unit ID	Capacity (MW)	Prime Mover[a]	Energy Source[b]	In-Service Date	Operating Status	Net Generation (MWh)	Capacity Utilization[c]	ID of Associated CWIS
1	446	ST	BIT	Oct. 1970	Operating	2,220,110	56.9%	OTC1
ST2	446	ST	BIT	Apr. 1973	Operating	2,235,357	57.3%	OTC2
ST3	446	ST	BIT	May 1976	Operating	2,094,605	53.7%	OTC3
ST4	486	ST	BIT	Feb. 1985	Operating	2,502,326	58.8%	OTC4
GT1	18	GT	FO2	Feb. 1969	Operating	70,101	4.6%	Not Applicable
GT2	79	GT	FO2	Nov. 1974	Operating			
GT3	79	GT	FO2	Nov. 1974	Operating			
Total	1,998					9,122,499	52.1%	

[a] Prime mover categories: ST = steam turbine, GT = gas turbine.
[b] Energy source categories: BIT = Bituminous Coal, FO2 = No. 2 Fuel Oil.
[c] Capacity utilization was calculated by dividing the unit's actual net generation by the potential generation if the unit ran at full capacity all the time (i.e., capacity * 24 hours * 365 days).
Source: U.S. DOE, 2001b; U.S. DOE, 2001a (Net Generation and CWIS ID); U.S. DOE, 2001d (GT Net Generation).

Figure D2-1 below presents Big Bend's electricity generation history between 1970 and 2000.

Figure D2-1: Big Bend Net Electricity Generation 1970-2000 (in MWh)



Source: U.S. Department of Energy, 2001d.

b. F.J. Gannon

During 1999, the F.J. Gannon power plant operated seven active units. Six of these are coal-fired steam-electric units that use cooling water withdrawn from Hillsborough Bay (Units 1-6). The seventh unit is a small gas turbine (GT1). The steam-electric units began operation between September 1957 and October 1967.

F.J. Gannon's total net generation in 1999 was 5.0 million MWh. The capacity utilization of the steam units ranged from 38.4 percent (Unit 6) and 55.8 percent (Unit 5).[1] Table D2-2 presents details for F.J. Gannon's seven units. It should be noted that this information represents pre-repowering operating conditions and may no longer be applicable once the conversion to combined-cycle units is completed.

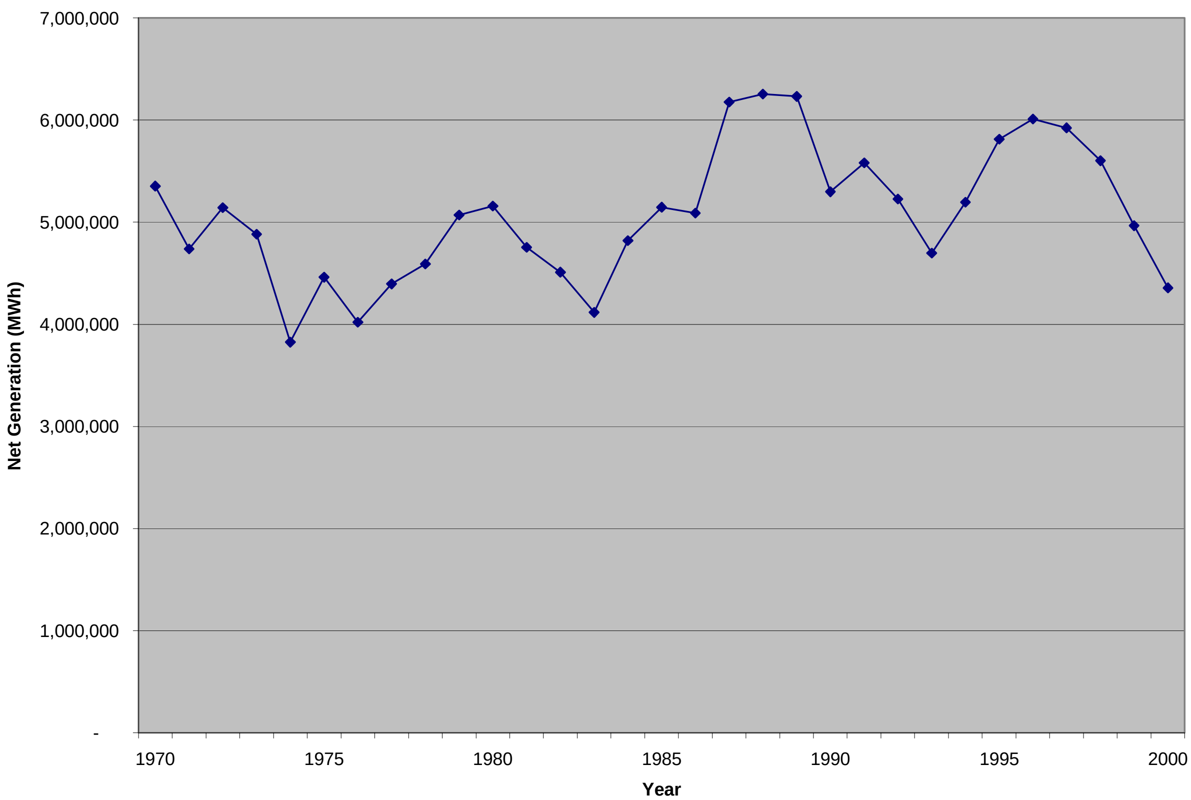
Figure D2-2 below presents F.J. Gannon's electricity generation history between 1970 and 2000.

[1] Unit 6 experienced an explosion in April 1999 (Hundley, 1999) and was off-line for approximately two months. Net generation and capacity utilization for Unit 6 may therefore under-represent "normal" operating conditions.

Table D2-2: F.J. Gannon Generator Characteristics (1999)								
Unit ID	**Capacity (MW)**	**Prime Mover[a]**	**Energy Source[b]**	**In-Service Date**	**Operating Status**	**Net Generation (MWh)**	**Capacity Utilization[c]**	**ID of Associated CWIS**
1	125	ST	BIT	Sep. 1957	Operating	476,668	43.5%	OTC1
2	125	ST	BIT	Nov. 1958	Operating	434,667	39.7%	OTC2
3	180	ST	BIT	Oct. 1960	Operating	725,338	46.1%	OTC3
4	188	ST	BIT	Nov. 1963	Operating	655,398	39.9%	OTC4
5	239	ST	BIT	Nov. 1965	Operating	1,170,215	55.8%	OTC5
6	446	ST	BIT	Oct. 1967	Operating	1,500,422	38.4%	OTC6
GT1	18	GT	FO2	Mar. 1969	Operating	3,736	2.4%	Not Applicable
Total	**1,320**					**4,966,444**	**43.0%**	

[a] Prime mover categories: ST = steam turbine; GT = gas turbine.
[b] Energy source categories: BIT = bituminous coal; FO2 = No. 2 Fuel Oil.
[c] Capacity utilization was calculated by dividing the unit's actual net generation by the potential generation if the unit ran at full capacity all the time (i.e., capacity * 24 hours * 365 days).
Source: U.S. DOE, 2001b; U.S. DOE, 2001a (Net Generation and CWIS ID); U.S. DOE, 2001d (GT Net Generation).

Figure D2-2: F.J. Gannon Net Electricity Generation 1970-2000 (in MWh)



Source: U.S. DOE, 2001d.

c. Hookers Point

During 1999, the Hookers Point power plant operated five units. All units are oil-fired steam-electric units that use cooling water withdrawn from Hillsborough Bay. The five units began operation between July 1948 and May 1955.

Hookers Point's total net electricity generation in 1999 was 184 thousand MWh. The capacity utilization of Hookers Point's units is low, between 7.6 percent (Unit 4) to 12.2 percent (Unit 3), for a plant total of 9.0 percent.

Table D2-3 presents details for Hookers Point's five units.

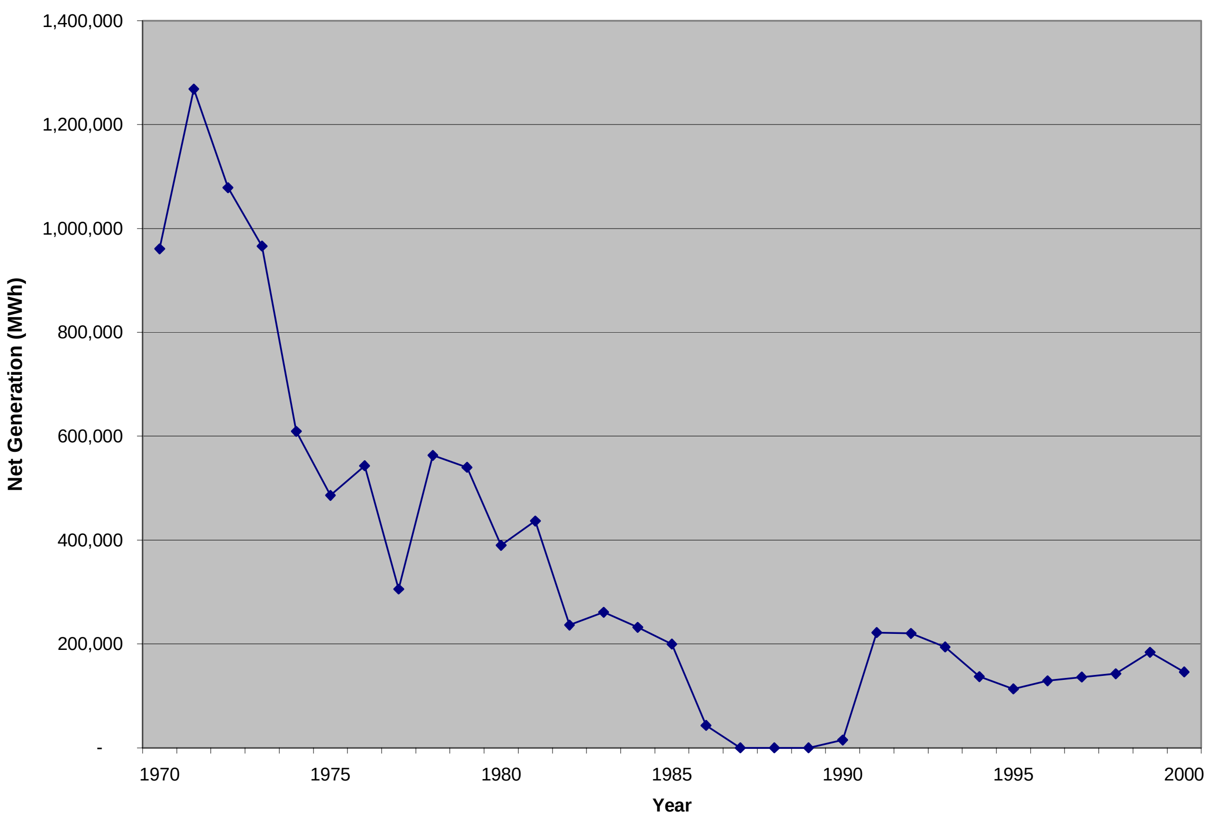
Table D2-3: Hookers Point Generator Characteristics (1999)

Unit ID	Capacity (MW)	Prime Mover[a]	Energy Source[b]	In-Service Date	Operating Status	Net Generation (MWh)	Capacity Utilization[c]	ID of Associated CWIS
1	33	ST	FO6	Jul. 1948	Operating	22,261	7.7%	OTC1-4
2	35	ST	FO6	Jun. 1950	Operating	34,747	11.5%	OTC1-4
3	35	ST	FO6	Aug. 1950	Operating	36,899	12.2%	OTC1-4
4	49	ST	FO6	Oct. 1953	Operating	32,520	7.6%	OTC1-4
5	82	ST	FO6	May 1955	Operating	57,230	8.0%	OTC5
Total	233					183,657	9.0%	

[a] Prime mover categories: ST = steam turbine.
[b] Energy source categories: FO6 = No. 6 Fuel Oil.
[c] Capacity utilization was calculated by dividing the unit's actual net generation by the potential generation if the unit ran at full capacity all the time (i.e., capacity * 24 hours * 365 days).
Source: U.S. DOE, 2001b; U.S. DOE, 2001a (Net Generation and CWIS ID).

Figure D2-3 below presents Hookers Point's electricity generation history between 1970 and 2000.

Figure D2-3: Hookers Point Net Electricity Generation 1970-2000 (in MWh)



Source: U.S. DOE, 2001d.

d. P.L. Bartow

During 1999, the P.L. Bartow power plant operated seven units. Three are steam electric units, two oil-fired (Units ST1-ST2) and one natural gas-fired (Unit ST3). The remaining four are smaller gas turbine units, two oil-fired (P1, P3) and two natural gas-fired (P2, P4). The steam turbine units began operation between September 1958 and July 1963 (Units ST1-ST3). The gas turbine units all began operation in May and June of 1972 (P1-P4).

P.L. Bartow's total net generation in 1999 was 2.6 million MWh. The steam-electric units accounted for almost 95 percent of total net generation. The capacity utilization of these three units was between 47.6 percent (ST2) and 62.5 percent (ST3).

Table D2-4 presents details for P.L. Bartow's seven units.

Table D2-4: P.L. Bartow Generator Characteristics (1999)

Unit ID	Capacity (MW)	Prime Mover[a]	Energy Source[b]	In-Service Date	Operating Status	Net Generation (MWh)	Capacity Utilization[c]	ID of Associated CWIS
ST1	128	ST	FO6	Sep. 1958	Operating	582,039	52.1%	1
ST2	128	ST	FO6	Aug. 1961	Operating	531,551	47.6%	1
ST3	239	ST	NG	Jul. 1963	Operating	1,310,304	62.5%	1
P1	56	GT	FO2	May 1972	Operating	139,587	7.1%	Not applicable
P2	56	GT	NG	Jun. 1972	Operating			
P3	56	GT	FO2	Jun. 1972	Operating			
P4	56	GT	NG	Jun. 1972	Operating			
Total	**717**					**2,563,481**	**40.8%**	

[a] Prime mover categories: ST = steam turbine; GT = gas turbine.
[b] Energy source categories: FO6 = No. 6 Fuel Oil; NG = Natural Gas; FO2 = No. 2 Fuel Oil.
[c] Capacity utilization was calculated by dividing the unit's actual net generation by the potential generation if the unit ran at full capacity all the time (i.e., capacity * 24 hours * 365 days).
Source: U.S. DOE, 2001b; U.S. DOE, 2001a (Net Generation and CWIS ID); U.S. DOE, 2001d (GT Net Generation).

Figure D2-4 below presents P.L. Bartow's electricity generation history between 1970 and 2000.

D2-2 CWIS Configuration and Water Withdrawal

This section describes cooling water intake structure technologies at the case study facilities.

a. Hookers Point

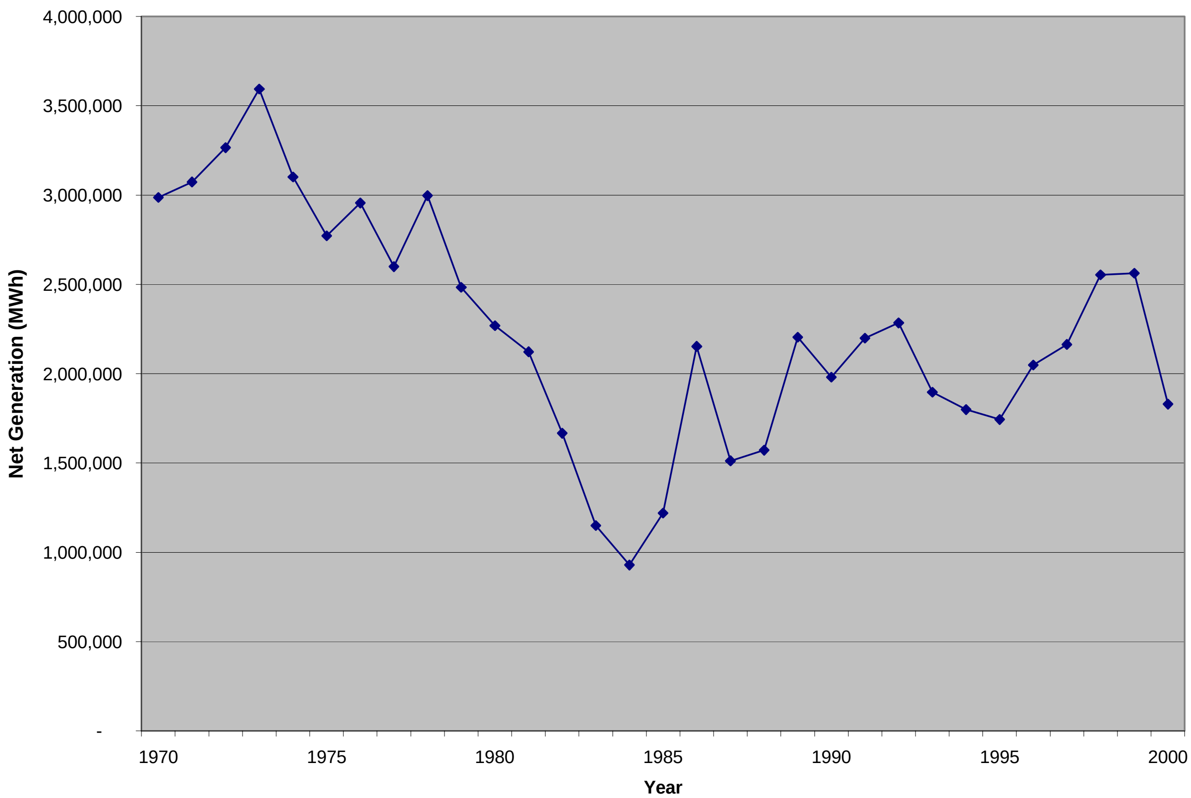
The Hookers Point facility is located in the Sparkman Channel, upstream of the Tampa Bay, approximately 25 miles from the mouth of the bay. The facility has two intake structures, each intake supplies a separate once through cooling system. These intakes are both submerged shoreline intakes.

According to survey data, the facility withdraws approximately 70 million gallons per day (MGD). An estimated design intake flow (DIF) was calculated at 123 MGD for this facility.[2]

Hookers Point also employs a passive intake system at its intake structure.

[2] Design intake flows were not requested in the short technical survey. As such, an estimated DIF was calculated for these facilities, using other information about the facility (actual intake flow and operating days).

Figure D2-4: P.L. Bartow Net Electricity Generation 1970-2000 (in MWh)



Source: U.S. DOE, 2001d.

b. P.L. Bartow

The Bartow facility is located in a northwest branch of Tampa Bay, approximately 15 miles from the mouth of the bay. The facility has one intake structure located in a manmade canal on the bay which supplies water to a once through cooling system. The canal is 1180 feet in length and 25ft deep at the intake structure. The facility has a design intake flow of 476 MGD, according to survey data.

The intake structure is comprised of six subsurface intake bays flush with the shoreline. Each intake bay is similarly designed and has a design through-screen velocity of 13 ft/sec. Cooling water first passes through a trash rack, and then a vertical traveling screen. The screens do have a spray wash system for debris, which empties directly into the bay. Cooling water is discharged via a separate channel.

c. Big Bend

Due to the presence of fine mesh traveling screens and a fish conveyance at Big Bend, the benefits analysis is separated into two distinct scenarios: the first, an analysis with these technologies functioning and the second with them not in use. The distinctions are explained below.

❖ ***Scenario 1***

Big Bend Power Station is located along the eastern shore of Tampa Bay, approximately 20 miles from the mouth of the bay. The facility has two intake structures, each supplying two generating units and their respective cooling systems. Both intakes are once through systems and located in an intake canal of over 3000 feet in length. The facility has a design intake flow of 1395 MGD, according to survey data. Originally, the facility was to use a closed cycle recirculating cooling system–a spray channel–for its cooling needs. However, during its construction in 1975, Tampa Electric concluded that this technology was not necessary for Big Bend to comply with the recently developed 316 requirements and a once through with dilution system was constructed instead. (Stone and Webster, 1980a) The dilution pumps have since been taken permanently offline. (U.S. EPA, 2001c)

Each intake structure is made up of 4 intake bays. Cooling water passes through a double entry/single exit traveling screen (dual flow with 3/8" mesh size) with a spray wash for debris. The design through screen velocity is approximately 9.5 ft/sec, (U.S. EPA, 2001c) although previous documents showed that the design through screen velocities for Units 1-3 were approximately 1.93 ft/sec. (Stone and Webster, 1980a).

Based on the findings from a monitoring study (Stone and Webster, 1980b), a fine mesh traveling screen (with a spray wash) and a fish conveyance (which empties beyond the influence of the facility) were installed on Intake 2 to reduce entrainment mortality. These technologies are operated from March 15 to October 15th, in place of the conventional intake technologies, which are returned to use in the other months. These screens have been found to be between 86% and 95% effective in reducing entrainment when operating, but have encountered operational difficulties in the past that may inhibit their effectiveness. However, for this scenario, it was assumed that the technologies are fully operational.

❖ ***Scenario 2***

The facility designed and installed a fine mesh traveling screen with a fish conveyance in 1985 when Unit 4 was built. It was intended to operate from March 15th to October 15th, the period of highest potential entrainment for the waterbody. However, due to operational problems with siltation in the screen well, there have been periods when the fine mesh screens were not implemented as required. In addition, dredging of the screen well has not been performed, as it may interfere with nearby manatee populations. For this scenario, it was assumed that the fine mesh screen and fish conveyance are non-functioning, thereby possibly requiring Big Bend to implement further technologies to reduce impingement and entrainment.

d. F.J. Gannon

Gannon Station is located approximately 25 miles from the mouth of Tampa Bay in the northeast section of the bay. The facility's cooling water system is once through and has one intake structure with six intake bays, one for each generating unit. The intake is located in a 1100 ft intake canal with a skimmer wall for intake bays 1, 2, and 3. According to survey data, the facility has a design intake flow of 2465 MGD.

Not all intake bays are similarly designed. Bays 1 and 2 have trash racks and the others do not. Bays 1, 2, and 3 use a vertical traveling screen, whereas bays 4, 5, and 6 each have a double entry/single exit traveling (dual flow) screen. The design through screen intake velocity varies between bays from 1.02 ft/sec (bay 1) to 1.61 ft/sec (bay 6).